MEMO TO	:	Regional Haze File
FROM	:	Tom Bachman, P.E. T.B. Senior Environmental Engineer Division of Air Quality
RE	:	Coal Creek BART for NO_x
DATE	:	April 18, 2012

In February 2012, the Department received a revised copy of Great River Energy's report entitled "Coal Creek Station Units 1 and 2; Best Available Retrofit Technology Refined Analysis for NO_x Emissions". The primary cost associated with SNCR (based on no lost ash sales) is the reagent that is used for SNCR. URS, a consultant for Great River Energy, estimated that 1,155 lb/hr of urea would be required in each boiler to lower NO_x emissions from 0.153 lb/10^6 Btu to 0.122 lb/10^6 Btu, a 20% reduction. Since urea is usually fed into the boiler using a 50% solution of urea, the actual feed rate would be 2,310 lb/hr of a 50% solution. To determine if URS's estimate was reasonable, the EPA Air Pollution Control Cost Manual (hereafter Control Cost Manual) was reviewed. The Control Cost Manual provides an equation (Equation 1.15) to estimate the amount of reagent consumption.

$$m_{reagent} = \frac{(NO_{x\ in})\ (Q_B)\ (\acute{\eta}_{NOx})\ (NSR)\ (M_{reagent})}{(M_{NOx})\qquad (SR_T)}$$

Where:

$NO_{x\ in}$	=	Uncontrolled NO_x emission rate (lb/10^6 Btu)
Q_B	=	Boiler heat input (10^6 Btu/hr)
$\acute{\eta}_{NOx}$	=	NO_x removal rate
NSR	=	Normalized Stoichiometric Ratio
$m_{reagent}$	=	Molecular Weight of Reagent (60.06 for urea)
M_{NOx}	=	Molecular Weight of NO_x (use 46.01)
SR_T	=	Ratio of equivalent moles of NH_2 per mole of reagent injected (2 for urea)

For Coal Creek Unit 2:

$NO_{x\ in}$	=	0.153 lb/10^6 Btu
Q_B	=	6,022 x 10^6 Btu/hr
$\acute{\eta}_{NOx}$	=	(0.153 – 0.122) / (0.153) = 0.203
NSR	=	$\frac{[(2)\ (NO_{x\ in}) + 0.7]\ (\acute{\eta}_{NOx})}{(NO_{x\ in})}$

$$\text{NSR} = \frac{[(2)(0.153) + 0.7](0.203)}{0.153}$$

$$\text{NSR} = 1.335$$

$$m_{reagent} = \frac{(0.153)(6022)(0.203)(1.335)(60.06)}{(46.01)(2)}$$

$m_{reagent}$ = 163 lb/hr of urea (100%)

$m_{reagent}$ = 326 lb/hr of 50% urea

Because of the large discrepancy between the Control Cost Manual and URS's predicted urea usage, I contacted Minnkota Power Cooperative to determine the amount of urea they were using in their Unit 2 SNCR system (see attached email). Minnkota indicated they are using between two and eight gallons per minute of 50% urea solution (1,737,997 gallons in 2011) with an ammonia slip around 1.5 ppm (5 ppm guaranteed by the supplier). Two to eight gallons per minute is 1,140 to 4,560 lb/hr of 50% urea solution (specific gravity = 1.14).

Rate = (2 gpm) (8.333 lb/gal) (1.14) (60 minutes/hr)
Rate = 1,140 lb/hr

Rate = (8 gpm) (8.333 lb/gal) (1.14) (60 minutes/hr)
Rate = 4,560 lb/hr

Minnkota is reducing NO_x emissions from 0.40 lb/10^6 Btu (2009 annual average – prior to SNCR installation) to 0.32 lb/10^6 Btu (2011 annual average – after SNCR installation). In 2011, Unit 2 at the M.R. Young Station had a heat input of 4.1664 x 10^{13} Btu and operated 8,385 hours (see attached data from Clean Air Markets Division). The average heat input was:

H.I. = (4.1664 x 10^{13} Btu) ÷ (8,385 hr)
H.I = 4,969 x 10^6 Btu/hr

Using Equation 1.15 from the Control Cost Manual, the expected urea usage rate can be calculated as follows:

$$\acute{\eta}_{NOx} = \frac{(0.40 - 0.32)}{(0.40)} = 0.20$$

$$\text{NSR} = \frac{[(2)(0.40) + 0.7](0.20)}{(0.40)}$$

$$\text{NSR} = 0.75$$

$$m_{reagent} = \frac{(0.40)(4,969)(0.20)(0.75)(60.06)}{(46.01)(2)}$$

$m_{reagent}$ = 195 lb/hr (100% urea)

$m_{reagent}$ = 390 lb/hr (50% urea)

As noted above, Minnkota is feeding between 1,140 and 4,560 lb/hr of 50% urea solution to achieve the 0.08 lb/10^6 Btu NO_x reduction. The ratio of the actual feed rate to the predicted feed rate (from Control Cost Manual) is:

Lower Feed Rate Ratio = (1,140) / (390) = 2.92

Upper Feed Rate Ratio = (4,560) / (390) = 11.69

If you apply these ratios to the urea feed rate predicted by the Control Cost Manual for Coal Creek Station Unit 2, the actual urea feed rate (50% solution) would be :

Lower Coal Creek Expected Feed Rate	=	(2.92) (326 lb/hr)
	=	952 lb/hr
Upper Coal Creek Expected Feed Rate	=	(11.69) (326 lb/hr)
	=	3,811 lb/hr

URS has estimated that 2,310 lb/hr of 50% urea solution will be necessary to achieve the required NO_x reduction (20.3%). URS's estimate of 2,310 lb/hr falls about in the middle of the range predicted (based on actual usage at M.R. Young Station Unit 2).

The large discrepancy between the amount of reagent usage predicted by the Control Cost Manual and the actual usage can be explained by closely examining the Control Cost Manual. Equation 1.15 predicts the amount of urea consumed by the NO_x it reacts with. However, it does not predict the loss of urea due to combustion or ammonia slip. Equation 1.13 provides an estimation of the "utilization" of the reagent. The Control Cost Manual states "Reagent utilization is the ratio of moles of reagent reacted to the moles injected."

(Eq. 1.13) $$\text{Utilization} = \frac{\acute{\eta}_{NOx}}{NSR}$$

In the case of M.R. Young Station Unit 2, the estimated utilization is:

$$\text{Utilization} = \frac{0.20}{0.75} = 26.7\%$$

This utilization rate is consistent with the latest revisions to the Integrated Planning Model (IPM) model which states "A utilization factor of 15% is used for units with an inlet NOx of 0.3 lb/MMBtu or lower and 25% for units with an inlet NOx greater than 0.3 lb/MMBtu." (*IPM Model – Revisions to Cost and Performance for APC Technologies; SNCR Cost Development Methodology; August 2010)*

Based on actual usage and the amount of reagent consumption from Equation 1.15, M.R. Young Station Unit 2 "utilization" is:

$$\text{Upper Utilization} = \frac{390 \text{ lb/hr}}{1{,}140 \text{ lb/hr}} = 0.342\ (34.2\%)$$

$$\text{Lower Utilization} = \frac{390 \text{ lb/hr}}{4{,}560 \text{ lb/hr}} = 0.085\ (8.5\%)$$

The utilization predicted by Equation 1.13 (26.7%) falls within this range. Even with the low utilization rate, Minnkota has measured ammonia slip at only 1.5 ppm, which is very low for an SNCR system.

For Coal Creek Station Unit 2, the predicted utilization is:

$$\text{Utilization} = \frac{0.203}{1.335} = 0.152\ (15.2\%)$$

Again, 15.2% is consistent with the latest IPM default utilization of 15%.

Based on 15.2% utilization, the expected feed rate of urea (50% solution) at Coal Creek 2 would be:

$$\text{Expected Feed Rate} = \frac{(326 \text{ lb/hr})}{(0.152)} = 2{,}116 \text{ lb/hr}$$

If you consider just the annual urea (50% solution) usage at M.R. Young Station Unit 2 in 2011, this equates to 1,968 lb/hr (annual average).

$$\text{Annual Average Feed Rate} = \frac{(1{,}737{,}997 \text{ gal/yr})(8.33 \text{ lb/gal})(1.14)}{8{,}385 \text{ hr}} = 1{,}968 \text{ lb/hr}$$

The actual annual average utilization rate for M.R. Young Station Unit 2 (using the results of Equation 1.15) is:

$$\text{Actual Utilization} = \frac{(390 \text{ lb/hr})}{(1{,}968 \text{ lb/hr})} = 0.198\ (19.8\%)$$

If the actual utilization of urea at Coal Creek Station is less than predicted by Equation 1.13 (as it is at M.R. Young 2), the expected urea feed rate (50% solution) could be:

Possible Usage = [(326 lb/hr)/(0.152)] * [(0.267)/(0.152)] = 2,892 lb/hr

The Integrated Planning Model (IPM) also estimates the amount of urea required for the SNCR system to achieve the desired emissions reduction. To reduce the NO_x emission rate from 0.153 lb/10^6 Btu to 0.122 lb/10^6 Btu (20% reduction), the IPM estimates that 800 lb/hr of urea (1,600 lb/hr of 50% solution) is required. This estimate is based on a normalized stoichiometric rate (NSR) of 1.0 and a utilization factor of 15%. If the NSR is adjusted to 1.335 as calculated from Equation 1.14, the urea usage (50% solution) would be 2,136 lb/hr. This is very similar to GRE's estimate of 2,310 lb/hr.

Minnkota, in their email, pointed out that the urea feed rate is dependent on a number of factors such as boiler cleanliness and coal quality. Generally, Coal Creek Station burns coal of lower quality (i.e. lower heat content) than M.R. Young Station. Based on the above, it appears that Great River Energy's (URS) estimate of reagent usage of 2,310 lb/hr is reasonable.

TB:csc

Bachman, Tom A.

From: Kevin Thomas [kthomas@minnkota.com]
Sent: Thursday, March 08, 2012 2:56 PM
To: Bachman, Tom A.
Subject: FW: SNCR

Tom,

We used 1,737,997 gallons of 50% urea in Unit 2 in 2011.

-----Original Message-----
From: Bachman, Tom A. [mailto:tbachman@nd.gov]
Sent: Wednesday, March 07, 2012 7:52 AM
To: Kevin Thomas
Subject: RE: SNCR

Kevin:

Can you tell me how many gallons (total) of 50% urea solution were used in Unit 2 in 2011?

Thanks!

Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

-----Original Message-----
From: Kevin Thomas [mailto:kthomas@minnkota.com]
Sent: Wednesday, February 22, 2012 7:26 AM
To: Bachman, Tom A.
Subject: RE: SNCR

Let me know if you need any additional information.

Kevin Thomas, P.E.
Senior Environmental Engineer
Minnkota Power Cooperative, Inc.
Phone (701)794-8711
Fax (701)794-7258

From: "Bachman, Tom A." <tbachman@nd.gov>

To: 'Kevin Thomas' <kthomas@minnkota.com>

Date: 02/22/2012 07:21 AM

Subject: RE: SNCR

Thanks Kevin!

Tom Bachman, P.E.
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

-----Original Message-----
From: Kevin Thomas [mailto:kthomas@minnkota.com]
Sent: Tuesday, February 21, 2012 3:38 PM
To: Bachman, Tom A.
Cc: Craig Bleth; John Graves
Subject: SNCR

Tom,

From a quick look at our Urea flow data compared to generator output we are injecting from 2 to 8 gallon per minute at about 470 MW. The wide range is a function of a number of factors such as boiler cleanliness and coal quality. I did also find a short period where we were injecting 10 gallon per minute at about 335 MW. The Urea we inject is 50 percent solution.

The typical slip we have measured is down around 1.5 ppm which is actually below the detection limit. As we discussed the performance guarantee for ammonia slip is 5 ppm. We have not tested any of our fly ash for any ammonia compounds.

Kevin Thomas, P.E.
Senior Environmental Engineer
Minnkota Power Cooperative, Inc.
Phone (701)794-8711
Fax (701)794-7258

Unit Level Emissions Quick Report
February 24, 2012

Your query will return data for 7 facilities and 12 units.

You specified: **Year(s):** 2011 **Program:** ARP **State(s):** ND

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	# of Months Reported	SO_2 Tons	Avg. NO_x Rate (lb/mmBtu)	NO_x Tons	CO_2 Tons	Heat Input (mmBtu)
ND	Antelope Valley	6469	B1		2011	ARP	6,148	12	5,176.2	0.34	4,284.4	2,634,366.8	24,197,378
ND	Antelope Valley	6469	B2		2011	ARP	8,558	12	8,730.3	0.34	6,263.3	3,922,343.5	36,027,754
ND	Coal Creek	6030	1		2011	ARP	7,583	12	7,161.2	0.20	4,397.7	4,683,023.6	43,014,802
ND	Coal Creek	6030	2		2011	ARP	8,364	12	7,905.6	0.15	3,579.8	5,110,647.9	46,942,626
ND	Coyote	8222	B1		2011	ARP	8,124	12	13,423.6	0.73	13,018.8	3,873,508.9	35,579,248
ND	Leland Olds	2817	1		2011	ARP	6,632	12	13,218.8	0.25	1,457.1	1,268,737.0	11,653,716
ND	Leland Olds	2817	2		2011	ARP	7,191	12	25,571.4	0.30	3,515.7	2,575,970.9	23,660,990
ND	Milton R Young	2823	B1		2011	ARP	7,592	12	4,049.2	0.51	4,765.1	2,017,791.5	18,534,017
ND	Milton R Young	2823	B2		2011	ARP	8,385	12	1,868.6	0.32	6,705.5	4,535,979.9	41,664,019
ND	R M Heskett	2790	B2		2011	ARP	7,394	12	1,989.6	0.40	934.7	518,718.3	4,764,553
ND	Stanton	2824	1	MS1E, MS1W	2011	ARP	8,414	12	2,256.2	0.24	1,078.2	931,458.0	8,881,160
ND	Stanton	2824	10		2011	ARP	8,162	12	144.0	0.31	755.1	503,368.5	4,799,507
Total									**91,494.7**		**50,755.2**	**32,575,914.5**	**299,719,768**

NORTH DAKOTA
UTILITY BOILERS
ACTUAL NO_x EMISSIONS
($LB/10^6$ BTU)

COMPANY	PLANT	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
BASIN ELECTRIC POWER COOP.	AVS 1	0.34	0.33	0.33	0.34	0.39	0.38	0.36	0.39	0.38	0.35
BASIN ELECTRIC POWER COOP.	AVS 2	0.30	0.35	0.33	0.34	0.35	0.32	0.37	0.37	0.34	0.35
BASIN ELECTRIC POWER COOP.	LELAND OLDS 1	0.27	0.29	0.29	0.31	0.31	0.31	0.34	0.30	0.29	0.25
BASIN ELECTRIC POWER COOP.	LELAND OLDS 2	0.62	0.61	0.58	0.57	0.50	0.50	0.53	0.47	0.31	0.30
MINNKOTA POWER COOP.	M.R. YOUNG 1	0.79	0.82	0.84	0.84	0.80	0.84	0.81	0.75	0.54	0.51
MINNKOTA POWER COOP.	M.R. YOUNG 2	0.81	0.77	0.81	0.83	0.81	0.86	0.46	0.40	0.41	0.32
OTTERTAIL POWER CO.	COYOTE	0.72	0.72	0.74	0.69	0.67	0.69	0.77	0.77	0.70	0.73
MONTANA DAKOTA UTILITIES	HESKETT 1	0.41	0.41	0.40	0.41	0.41	0.42	0.42	0.42	0.41	
MONTANA DAKOTA UTILITIES	HESKETT 2	0.31	0.29	0.28	0.25	0.27	0.36	0.36	0.36	0.37	0.39
GREAT RIVER ENERGY	STANTON 1	0.43	0.44	0.39	0.30	0.31	0.24	0.25	0.26	0.26	0.24
GREAT RIVER ENERGY	STANTON 10	0.35	0.34	0.31	0.30	0.26	0.25	0.30	0.26	0.25	0.31
GREAT RIVER ENERGY	COAL CREEK 1	0.21	0.20	0.21	0.22	0.24	0.26	0.25	0.25	0.21	0.20
GREAT RIVER ENERGY	COAL CREEK 2	0.22	0.22	0.24	0.24	0.25	0.20	0.18	0.20	0.17	0.15

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.0

Variable	Designation	Units	Value	Calculation
Boiler Type			TANGENTIAL	User Input
Unit Size	A	MW	601.5	User Input
Retrofit Factor	B		1	User Input "Average" = 1.0
Heat Rate	C	Btu/kw-hr	10000	User Input
NOx Rate	D	lb/MMbtu	0.153	User Input
SO2 rate	E	lb/MMBtu	2	User Input
Type of Coal			lignite	User Input
Coal Factor	F		1.07	Bit. = 1.0; PRB = 1.06; Lignite = 1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	Btu/hr	6.015E+09	A*C*1000
Capacity Factor	I		87	User Input
NOx Removal Eff.	J	%	20	User Input
NOx Removed	K	lb/hr	1.841E+02	$D*H/10^6*J/100$
Urea Rate (100%)	L	lb/hr	8.003E+02	K/UF/46*30 UF=0.25 FOR CFB OR D>0.3; OTHERWISE 0.15
Water Required	M	lb/hr	7202.308696	L*9
Aux. Power	N	%	0.05	
Dilution Water Rate	O	1000 gph	0.864277043	M*0.12/1000
Urea Cost 50% Soln.	P	$/ton	250	User Input
Aux. Power Cost	Q	$/kwh	0.06	User Input
Dilution Water Cost	R	$/kgal	3	User Input
Op. Labor Rate	S	$/hr	60	User Input
Capital Cost Calculation				
BMS	2,995,735			SNCR (Injectors, blowers, DCS, Reagent System) Cost
BMA	0			Air Heater Modifications
BMB	4,171,636			Balance of the Plant Cost (Piping, Including Site Upgrades)
BM	7,167,371			Total Bare Module Cost including retrofit factor
Total Project Cost				

IPM SNCR COST
COAL CREEK STATION
RETROFIT FACTOR = 1.0

A1	716,737			Engineering and Construction Management Costs (10% of BM)
A2	716,737			Labor Adjustment (10% of BM)
A3	716,737			Contractor Profit and Fees (10% of BM)
CECC	9,317,582			Capital, Engineering, and Construction Cost Subtotal (BM+A1+A2+A3)
B1	465,879			Owner's Cost (5% of CECC)
TPC	9,783,461			Total Project Cost (CECC + B1) (2009 dollars)

TPC (2011 dollars) = (9,783,461)(1.05) = $10,272,634